INTEGRATED ANALYSIS OF DEMAND-SIDE PROGRAMS

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Abstract

We use a case study of residential appliance efficiency standards in the Nevada Power Company service territory to illustrate an integrated method for evaluating the load shape and economic impacts of demand side utility programs. The method consists of four models: the LBL Residential Energy Demand Model, the DOE-2 Building Energy Analysis Model, the LBL Residential Hourly Load and Peak Demand Model, and the LBL Utility Financial Impact Model. Load impacts are modeled from the "bottom up" with end-use energy and hourly demand models. Benefits are calculated with the aid of a production cost model and methods adapted from avoided cost offers to cogenerators and small power producers. The analysis of avoided production costs explicitly considers perturbations in future supply plans resulting from demand-side load modifications. Utility and societal costs are compared to the benefits of appliance standards.

INTRODUCTION

Electric utility interest in demand-side programs (DSPs) is growing. Incorporating that interest into traditional planning activities is, however, a great challenge because forecasting the effects of DSPs is more difficult and less well understood than forecasting the effects of supply-side interventions. Furthermore, choosing a least-cost strategy from the range of options available requires integrating planning methods that are still evolving. At a minimum, demand-side and supply-side programs must be evaluated with a common set of economic and performance assumptions [5,11,12,13,14,15,17,19,22].

Forecasting the effects of DSPs is difficult because we are uncertain about the engineering characteristics of the hardware and behavioral characteristics of consumers. To evaluate DSPs, one must determine both the maximum amount of energy and demand a given program--a rebate for high efficiency central air conditioners, for example--can save, and how consumer purchase and usage patterns will translate that potential into system load impacts. In other words, the forecast must embody a logical and consistent analytic framework in which the load impacts of DSPs are not estimated by external *ad hoc* procedures, which might result either in double-counting or under-forecasting. As a result, end-use energy forecasts have become essential for DSP analyses [1,14].

Ideally, DSPs should be evaluated directly by measuring the cost changes to a re-optimized supply system (i.e., re-optimized to reflect the load impact of the DSP) on a program-by-program basis. In practice, the required iteration between supply- and demand-side requires tremendous analytical resources. For this reason, the concept of avoided cost, which is central to the development of utility offers to purchase power from small power producers and cogenerators, is a convenient starting point for evaluating DSPs. Like these power purchases, DSPs represent a marginal change in the loads placed upon the utility's generating system. The value of this change is properly measured by the utility's avoided production costs. Avoided costs, consequently, are the value of DSPs [17,19]. To simplify analysis of related DSPs, it is useful to consider generic supply-side adjustments. The avoided costs of such generic supply changes can be expressed as a tariff schedule, which can be readily used to measure the value of load impacts from DSPs similar to the "generic program". A principal contribution of work to be described is the use such a tariff schedule that is developed by measuring production cost changes which result from explicit changes in the timing of resource additions to the supply system.

87 SM 461-7 A paper recommended and approved by the IEEE Power System Engineering Committee of the IEEE Power Engineering Society for presentation at the IEEE/PES 1987 Summer Meeting, San Francisco, California, July 12 - 17, 1987. Manuscript submitted August 29, 1986; made available for printing May 19, 1987.

In 1984, the Department of Energy (DOE) directed the Lawrence Berkeley Laboratory (LBL) to study the impacts on individual utilities of standards mandating minimum levels of efficiency for residential appliances. DOE required LBL to perform both nationwide and utility-specific forecasts of energy and load shape impacts of the standards, as well as financial consequences of the standards. LBL was directed to consider both the perspectives of the utility and of society in its evaluation.

This paper describes the analysis method developed by LBL for these studies. We demonstrate the capabilities of the method with results from our case study of the Nevada Power Company (NPC) [6]. In addition, LBL has also used the method to study four other U.S. utilities: The Pacific Gas and Electric Company, The Texas Utilities Electric Company, The Virginia Electric and Power Company, and The Detroit Edison Company [7,8,9,10]. In the next section, we describe the individual models with special attention to the linking process that constituted our integrated analysis. The models include the LBL Residential Energy Model [18], the DOE-2 Building Energy Analysis Program [4], the LBL Residential Hourly and Peak Demand Model [25], the LBL Utility Financial Impact Model [6], and, as input to the latter, the production-cost module of the Telplan Utility Corporate Planning Model [23]. In the following section, we summarize our case study with a brief description of NPC, the appliance efficiency standards evaluated, and the predicted load shape and financial impacts of the standards.

METHOD

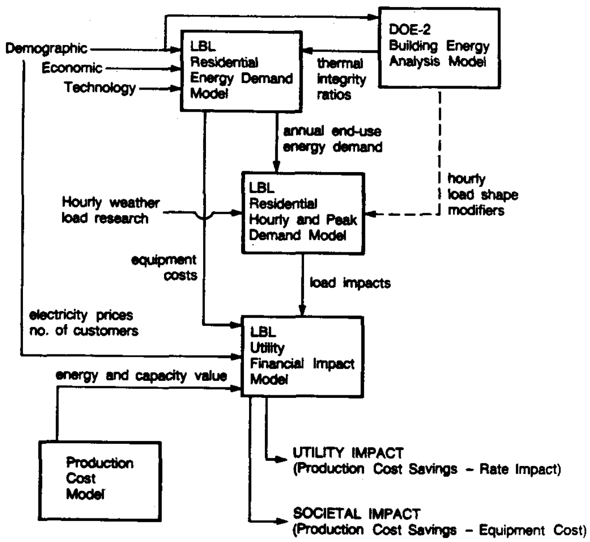
LBL has developed a four-part method to evaluate the impact of residential demand-side technologies on utility load shapes and finances. The general approach is to link the outputs of existing models, which, once linked, form an integrated demand-side program analysis tool. While the method is general in nature, the linkages between models are largely utility-specific. Data availability, for example, plays an important tempering role on the degree of disaggregation possible.

The components can be divided into two subcategories: load shape forecasts and economics. The heart of the load shape evaluation is the LBL Residential Energy Model, which is an end-use engineering/economic demand forecasting model [18]. End-use energy forecasts are central to an analysis of the load shape impacts of demand-side programs [1,14]. We also use a sophisticated building energy simulation model, DOE-2, to develop inputs to the forecasting model [4]. The forecasting model's outputs are converted

0885-8950/88/1100-1397$01.00©1988 IEEE

into hourly class load shapes by the LBL Residential Hourly and Peak Demand Model [25]. Economics are evaluated by the LBL Utility Financial Impact Model [6]. This model combines data on avoided production costs and revenues, and assigns them to the forecast load impacts. For the Nevada Power Company case study, we made independent estimates of avoided production costs using the Telplan Utility Corporate Planning Model [23]. In other case studies, we have relied on published avoided cost filings. The following subsections of the paper are an overview of the method, with more detailed descriptions of the models and of the flows of information between them (see Figure I).

Figure I.

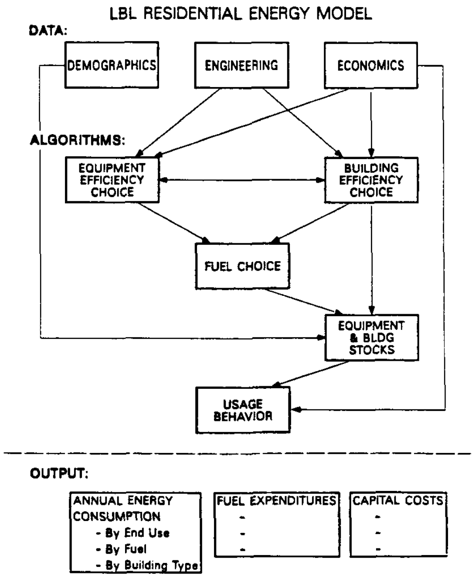


LBL Residential Energy Model

The LBL Residential Energy Model (LBLREM) is at the center of our demand-side program analysis [18]. LBLREM is an engineering/economic model that produces a twenty-year forecast of annual energy use for nine end-uses (space heating, air conditioning, water heating, refrigerators, freezers, cooking, clothes dryers, lighting, and miscellaneous). It forecasts energy consumption for all domestic fuels except wood. For example, the model's outputs describe not only electricity demand but also total household energy consumption, since the model explicitly accounts for interfuel substitution.

The driving forces for the LBLREM forecasts are projections of future energy prices, numbers of households, personal income, and housing thermal integrity characteristics. Given these data, LBLREM performs five major calculations (see Figure II): future appliance efficiency choices, investments in thermal integrity improvements for buildings, turnover of housing units and appliances, changes in the market share for each technology and fuel (such as numbers of gas vs. electric water heaters), and changes in usage behavior (such as hours of air conditioner usage). These calculations rely on engineering and cost estimates of the range of appliance designs (or thermal integrity improvements) likely to be available, and on relationships describing the influence of energy and equipment prices, as well as income and other factors, on purchase and usage decisions. Purchase decisions and fuel choices for appliances are simulated according to economic criteria relating capital costs and efficiency; operation of the appliance stock is simulated according to engineering and economic criteria, and average weather conditions. Parameters representing consumer behavior are embedded in the appliance purchase algorithm. For all calculations, the fundamental household units can be represented by up to three sets of prototypes (e.g., single family, multifamily, and mobile home; or, alternatively, three residential rate classes).

Figure II.



The model is the product of a long development effort that began at Oak Ridge National Laboratory in the mid-1970's. After we adopted the model at LBL, we made numerous improvements [18]. For example, the revised model maintains a full distribution of appliance ages, and retires appliances in existing homes only after a fixed service lifetime. Therefore, the model has available a complete description of the stock at any time, including the distribution of efficiencies. Further, we adjusted the model to account for the effect on energy use of retirements of older (and hence less efficient) appliances. Another modification to the model was the creation of a specific appliance category for heat pumps, which were originally included with central air conditioning.

In its original form, LBLREM was (and continues to be) used for DOE-sponsored national analyses of appliance efficiency standards. For this project, we have adapted the model to forecast the impacts of appliance efficiency standards for individual utility service territories. The principal task in using the model at this level of detail is respecification of the input data based on local conditions. For the Nevada Power Company case study, we relied extensively on NPC's own data to develop these inputs. We have also used the model to forecast sales and peak demands for individual residential tariff classes [7].

Rate impacts, which arise when sales do not recover revenue requirements due to the effect of DSPs, are an important consideration in a comprehensive evaluation of DSPs [5,13,19,22]. (We will define the rate impact precisely in our discussion of the LBL Utility Financial Impact Model, below.) LBLREM is capable of incorporating rate impacts from DSPs. By running each of the major simulation models one year at a time, we could modify subsequent year forecasts by the impact of a given program on retail rates. Following conventional practice [13,19,22] we did not run the models in this fashion for the NPC case study. Our calculations indicate that the maximum effect of this feedback (assuming perfect regulation, and complete re-allocation to the residential class, also described below) was on the order of a 1 to 2% decrease in average residential retail rates.

DOE-2

The DOE-2 building energy analysis program is an auxiliary component to our analysis of load shaping technologies. The program is a well-documented, state-of-the-art tool for analyzing building energy performance [4]. It simulates the thermodynamics of a building by calculating non-linear flows of heat among all of the building's enclosed spaces and surfaces, on an hourly basis, using response factors that describe heat conduction and radiation through the building envelope. The user can specify building location, orientation, construction, material properties, HVAC and lighting systems, central plant equipment, as well as schedules of operation, occupancy, and use.

DOE-2 is a complex model and our ability to utilize it is compromised only by the availability of data. In principle, given complete specification of inputs for prototypes characterizing an entire rate class, DOE-2 could be a source of hourly load shape data (given also some exogenous measure of diversity). The data requirements, however, would be extremely large. Data limitations require us to use the model in auxilary capacity; i.e., we do not use the outputs of DOE-2 directly. Instead, we combine data from the utility and other sources with the extensive library of DOE-2 default values to develop scaling factors, which assist us in developing model inputs. For example, utilities often have estimates of heating and cooling energy use for only a stock-weighted prototypical existing residence in the service territory. LBLREM, however, requires this information for both this prototypical residence and for the new or marginal residence. DOE-2 provides an engineering basis to scale the thermal energy requirements for existing residences to those for new residences. The procedure requires two simulations, one of the existing residence and one of the new residence. Both simulations are based on available data from the utility on major features of these two house types (levels of insulation, number of glazings, etc.). The ratio of heating (or cooling) loads between the new and the existing residence becomes a scaling factor that converts utility-supplied estimates for the stock to those for new residences.

LBL Residential Hourly and Peak Demand Model

Hourly load profiles are essential for linking energy forecasts to financial impacts [1,2,14]. The LBL Residential Hourly and Peak Demand Model performs this task by distributing annual end-use electricity forecasts from LBLREM into annual hourly demand profiles for each day of the year [25]. The model uses metered data collected by utility-sponsored load research studies.

Space-conditioning load profiles are calculated with data from an hourly weather tape and sets of empirically-derived matrices that relate consumption in a given hour to climatic conditions. Each matrix is a series of weights, which describe the fraction of the appliance stock that would be running under the conditions specified by the weather tape. These weights are summed at the end of the simulation year and are used to allocate annual energy use to individual hours of the year.

In general, every end-use calculation follows this logic of proportional weighting. For example, efficiency improvements are represented by proportional downward shifts in the load shape for a given end-use. This approach is limited by its inability to model technologies with very specific load shape impacts, which are distinct from a uniform change in consumption for all hours (e.g., two-speed compressors, which save energy but not capacity). To incorporate load shapes changes from these technologies, a more complex analysis would be required. These complexities were not required for our analysis since the efficiency improvements analyzed did not assume technological improvements that would modify the basic load shape of the end-use.

The LBL Residential Hourly and Peak Demand Model plays an important role in calibrating the LBLREM. Before we forecast the impacts of standards, we extensively calibrate the models to both historical and utility projected data. The LBL Residential Hourly and Peak Demand Model increases accuracy by placing additional constraints on the process. For example, our calibration to NPC historical data included comparisons of monthly sales and class peak demands, as well as analysis of summer and winter peak days, based on historic weather conditions. We have described these efforts in [6].

Figures III and IV contain samples of our calibrated, benchmark results for historical NPC winter and summer, peak day, hourly energy use. These figures indicate that we have achieved reasonable, but not exact, agreement with historical data. Discrepancies will largely cancel-out in estimating the impacts of DSPs, since we use differences in loads as our measure of load savings.

Figure III.

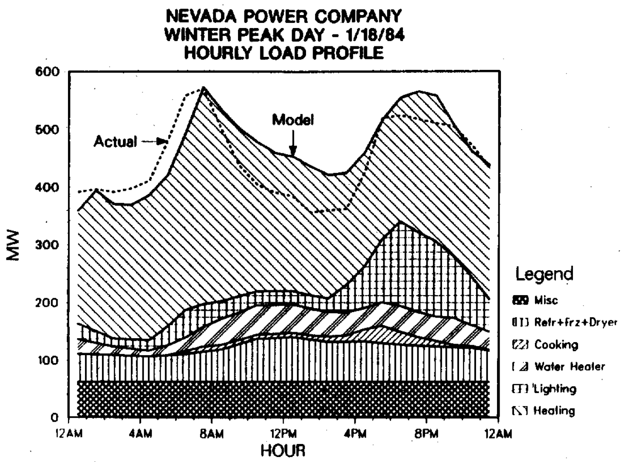
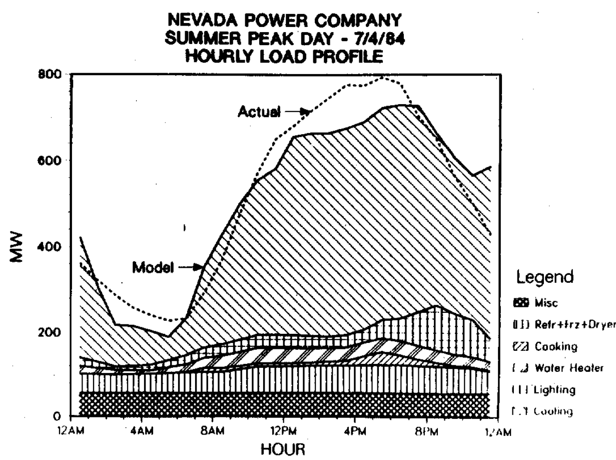


Figure IV.



LBL Utility Financial Impact Model

The final step in our analyses is to determine the economic consequences of forecast load shape changes. The LBL Utility Financial Impact Model considers these consequences from both the utility's and society's perspectives. The utility perspective compares the benefits from both long- and short-run avoided production expenses to the costs resulting from changes in the recovery of fixed costs due to "lost revenues". Analyses of utility-sponsored programs would properly include the cost of the programs themselves, but our analysis of the impact of minimum appliance efficiency standards assumes that no costs would be incurred by the utility. The societal perspective compares the incremental capital and labor cost of more efficient appliances to the avoided production expenses. Each perspective is evaluated with a separate discount rate. To determine the utility perspective, we used the utility's weighted average cost of capital; for the societal perspective, we used a lower rate, which approximates a social discount rate. For the NPC case study, we used 15.07% as the discount rate for the utility perspective and 11.85% as the discount rate for the societal perspective, based on the then current NPC resource plan [21].

The financial model is essentially an accounting tool for assigning dollar-values to forecast load shape impacts. The source of these values and the valuation procedures employed by the model are, however, unique to our analyses. For example, the accuracy of our results was enhanced by the use of a production-cost model to calculate long- and short-run avoided production costs. A principal contribution of our analysis is the identification of long-run avoided production cost savings that result from deferring future generating units in responses to the large load impacts forecast by the demand models. Other LBL case studies have relied on utility avoided cost filings to determine avoided energy and capacity production cost benefits [7,8,9]. We will summarize major features of the evaluation, but direct the interested reader to a longer, more detailed review [16].

Independently derived estimates of the long- and short-run value of avoided production costs are calculated with the aid of the production-cost module of the Telplan Utility Corporate Planning Model [23]. We calculate long-run values by analyzing the results of iterative simulations of the NPC supply system. These simulations are designed to determine the optimal deferral period for future plants, based on forecast load shape impacts. Once determined, the long-run value is the fuel cost savings associated with the DSP that allows a revenue-neutral deferral [16]. Short-run values are calculated by simulating a static supply system under varying load conditions. A capacity-related or reliability benefit from the deferral is isolated from the long-run value, by convention, with a combustion turbine proxy [20].

Table I. Residential Class Coincidence Factors
Nevada Power Company, 1984

Month	Load at Time of System Peak (MW)	Maximum Load (MW)	Coincidence Factor
Jan	584	635	0.920
Feb	447	498	0.898
Mar	468	468	1.000
Apr	382	391	0.977
May	753	790	0.953
Jun	667	836	0.797
Jul	853	883	0.966
Aug	810	823	0.984
Sep	760	785	0.968
Oct	382	410	0.932
Nov	297	534	0.556
Dec	498	568	0.877

Source: Nevada Power Company, 1984 Hourly Loads

Determining the capacity value of load shape impacts for the residential class is complicated by the need to consider the coincidence of residential to system loads and the hours when the system is in need of capacity. Ideally, the latter should be measured by Loss-of-Load-Probability (LOLP). We address these issues by examining a conservative measure of the capacity value of residential load shape impacts. We assign capacity value to the difference between the average of the highest 500 hourly loads for the residential class before and after the implementation of standards. The definition is based on two considerations. First, analysis of NPC residential and system loads indicates a high degree of coincidence between residential and system loads, generally in excess of 90% (see Table I). (In other circumstances, lower coincidence factors would require more direct methods to determine system load shape impacts.) Second, in lieu of an analysis of hourly LOLP's, we examined NPC peaking plant operation, which indicated approximately 500 hours full-load operation for these units. Our results for the case study will compare this measure of the peak load impact with changes during the hour of greatest residential class load.

The cost of load shape impacts to the utility is the under-recovery of fixed costs through reduced electricity sales [19]. We define this term as the rate impact cost. It is measured by the difference between lost revenues and avoided variable operating expenses. When the utility features tiered or block rates, we use the block-adjustment procedure to calculate revenue losses [7,8]. In the absence of block rates, lost revenue is simply average retail rate times lost sales. Avoided variable operating expenses are estimated using short-run marginal costs. The rate impact cost can be a benefit, if short-run marginal costs exceed retail rates.

The inclusion of some measure of rate impacts in determining utility costs and benefits is common [5,13,19,22]. It is important, however, to distinguish our definition and use of this term from its use in traditional cost/benefit analyses. The under- (or over) recovery of fixed costs, due to less-than-forecast sales, are not costs (or benefits) from a societal perspective; they are simply transfer payments. The precise allocation between ratepayers or shareholders is a matter of regulation. Under perfect regulation, the under- (or over-) recovery will be allocated to ratepayers. Short of this ideal, shareholder returns will be affected. Even if we assume perfect regulation, the precise allocation to each rate class is also subject to regulatory determination. Finally, the net impact on retail rates is affected by the rate of sales growth. Increased sales will dilute the impact on rates, and decreased sales will accentuate it.

The cost of standards to society is measured by the incremental equipment cost of more efficient appliances. The relatively higher cost of efficient appliances has two impacts on the appliance market. First, those who purchase new appliances pay a higher price. Second, total purchases of appliances may change, either because higher equipment costs discourage purchasers or because lower operating costs encourage them. To account for the benefits properly, we multiplied the per-unit incremental equipment costs by the units purchased in the base case. The alternative, taking the difference between gross equipment expenditures in the policy and base cases (including changes in the number of units purchased) misrepresents the benefits. For example, if higher equipment costs cause a decrease in purchases of an appliance, then gross equipment costs in the policy case would be lower, which would appear as a benefit. Conversely, if lower operating costs induce more purchases, the higher gross equipment expenditures would be calculated as a cost. In the first instance, decreased amenity would appear as a benefit (with a maximum when no purchaser buys the more efficient appliance), and in the second instance, increased amenity would appear as a cost.

CASE STUDY

The subject of our case study is the residential class of the Nevada Power Company (NPC). The NPC service territory is located in the southwestern part of the U.S. and is roughly defined by the boundaries of Clark County, Nevada. Total sales in 1984 were 6572 GWh and peak demand was 1502 MW. The NPC residential class accounted for 44% of total sales in 1984.

NPC anticipates continued strong demand growth into the 1990's. According to the Base Case in NPC's 1984 Resource Plan, electricity consumption is expected to increase at 3.7%/year through 1999, and peak demands are expected to grow at 3.8%/year over the same period [21]. Together, these predictions suggest that growth will come at the expense of further declines in an already low load factor (49.9% in 1984). The greatest growth is expected in the residential and commercial classes. Given the coincidence between residential class and system loads (see Table I), appliance efficiency standards have important consequences for future NPC system load factors.

NPC costs are lower than national averages. In 1985, residential electric rates for 1000 kWh/mo were 0.058 $/kWh, compared to the national average for 1985 of 0.076 $/kWh [24]. The utility plans to increase coal-fired generation. As a result, Nevada Power expects, between 1985 and 1999, to reduce oil- and gas-fired generation from 14% to 6% of total generation. These low retail rates, coupled with expensive future supply plans, have important consequences for our financial analyses of standards.

We examined three separate residential appliance efficiency standards. The standards are modeled by imposing a minimum efficiency requirement for new equipment, starting in 1987. Table II compares the efficiencies mandated by each standard to existing appliance efficiencies. Existing efficiencies for 1985 are described by both an existing appliance average efficiency and a marginal (or new) appliance efficiency. The first policy, Level 8, consists of a set of minimum efficiencies that are cost-effective based on a life-cycle analysis using national data. Note that, for NPC, the minimum efficiencies for gas ranges and gas dryers are lower than the efficiencies of new appliance purchases; the standard will, consequently, have no effect for these appliances. The second policy, Level 8/12, incorporates the minimum efficiencies called for in the first standard, but in addition specifies an extremely high minimum efficiency level for central air conditioners and heat pumps (namely, SEER=12). The third policy, Level 12/AC, refers to the isolated case of increasing only room and central air conditioner efficiencies.

Table II. Comparison of Appliance Efficiency Standards

Appliance	1985 * Existing	1985 * New	Level 8	Level 8/12	Level 12/AC
Space Heating (AFUE %)					
gas	64.36	71.45	85.72	85.72	--
oil	75.08	78.77	90.98	90.98	--
Air Conditioning					
room (EER)	6.58	7.15	8.87	8.87	8.87
central (SEER)	7.08	7.26	8.42	12.00	12.00
Water Heating (%)					
electric	81.01	82.86	93.60	93.60	--
gas	53.03	62.61	81.75	81.75	--
Refrigerators (ft^3/kWh/d)	4.96	6.64	11.28	11.28	--
Freezers (ft^3/kWh/d)	9.86	12.24	22.34	22.34	--
Ranges (%)					
electric	39.40	44.27	47.51	47.51	--
gas	17.57	31.57	20.27	20.27	--
Dryer (dry lbs/kWh)					
electric	2.71	2.90	2.96	2.96	--
gas (3412 Btu/kWh)	2.28	2.65	2.61	2.61	--

AFUE - Annual Fuel Utilization Efficiency
EER - Energy Efficiency Ratio
SEER - Seasonal Energy Efficiency Ratio

*1985 values are those forecast by LBLREM; they are not measured data.

The load shape impacts of the three standards are summarized in Table III. Level 8 and Level 12/AC standards produce approximately the same reduction in sales growth (6%). The Level 8/12 standard reduces sales in 1996 by 10%. Examination of projected class peak demands gives a different picture of the effects of the policies. Level 8 standards reduce the 1996 peak by 2%. The Level 12/AC standard, while saving approximately the same amount of energy as the Level 8 standard, reduces load growth much more, by 12% in 1996. Level 8/12 achieves only a slight additional decrease in load growth --14% by 1996--compared to Level 12/AC.

Table III. Summary of Load Shape Impacts

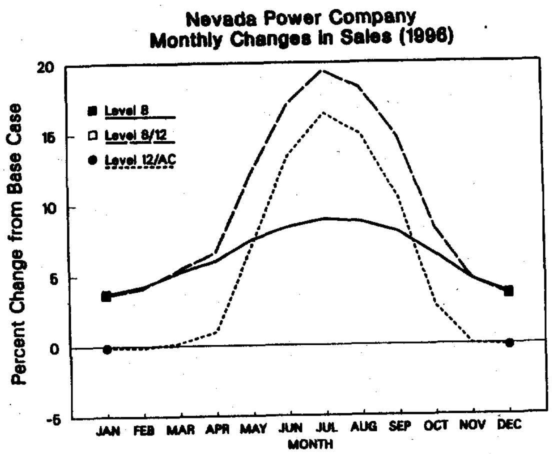
Nevada Power Company, Residential Class

Case	Growth (1987-1996) Energy (%/yr)	Growth (1987-1996) Demand (%/yr)	Load Factor (%)	Impact by 1996 * Energy (GWh)	Energy (%)	Peak Demand (MW)	Peak Demand (%)
Base	2.99	2.61	42				
Level 8	2.34	1.65	43	235.1	(6)	95.3	(9)
Level 8/12	1.92	0.11	48	380.3	(10)	227.2	(22)
Level 12/AC	2.37	0.36	49	226.1	(6)	207.1	(20)

* Energy and peak demand impacts are calculated relative to the base case.

The seasonal sales reductions for each policy are shown in Figure V. For all cases, sales are lower in the summer months than in other seasons. For the Level 8 standards, sales are reduced approximately 4% in winter and 9% in summer. For the Level 12/AC case, sales are not lower in winter, but are reduced 16% in summer. For the Level 8/12 case, winter sales are reduced approximately 5%, and summer sales are reduced 18%.

Figure V.



The effects of the standards on the hourly residential load shape for the peak summer day of 1996 are shown in Figure VI. As expected, the Level 8/12 and Level 12/AC standards yield the largest reduction in loads from the base case. That is, space cooling is clearly the dominant component of load in the summer (see Figure III).

Figure VI.

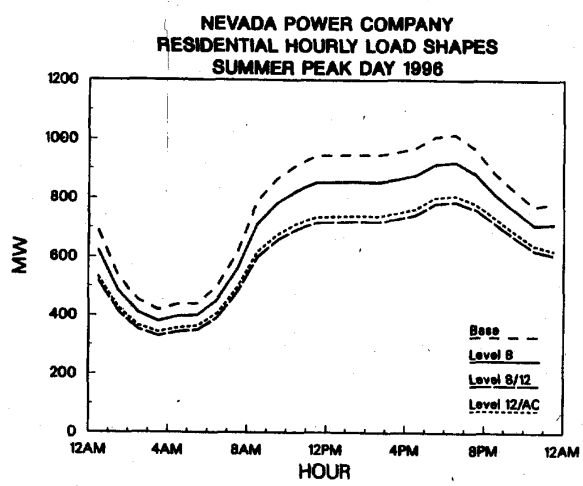


Table IV illustrates the effect of our valuation method on the capacity value of the standards. As expected, when the 500 maximum hourly load impacts are averaged, the capacity savings are less than the impact at the peak hour (also shown in Table III).

Table IV. 1996 Capacity Value for Standards

Nevada Power Company

Case	A Peak Hour Savings * (MW)	B System Capacity Value ** (MW)	(B/A)*100 Ratio (%)
Level 8	95.3	70.6	74
Level 8/12	227.2	142.7	63
Level 12/AC	207.1	122.7	59

* See Table III.

** Based on average change for highest 500 residential hourly loads.

Nevertheless, the load impacts are highly significant from a system-wide perspective. As noted above in Section II, the magnitude of these load impacts warrants deferral of future generating units.

Tables V and VI summarize the financial impacts of the standards from the perspectives of both the utility and society. For the utility perspective, note that the rate impact cost of each policy is not a cost, but a benefit to the utility. Under the current rate structure, marginal or avoided costs exceed average retail rates. Thus the sales "lost" by efficient appliances are a benefit since those sales, if made, would not recover the full costs of producing electricity.

Table V. Summary of Financial Impacts - Utility Perspective

(Discount Rate = 15.07%)

Standard	A Avoided Cost (M 1985$)	B Rate Impact (M 1985$)	A-B Net Impact (M 1985$)	(1985$/kWh) *
Level 8	62	(15)	77	0.33
Level 8/12	107	(25)	132	0.35
Level 12/AC	74	(17)	91	0.40

* Per unit values, in 1985$/kWh, represent the present value of savings over the lifetime of the appliances (12 years).

Table VI. Summary of Financial Impacts - Societal Perspective

(Discount Rate = 11.85%)

Standard	A Avoided Cost (M 1985$)	B Equipment (M 1985$)	A-B Net Impact (M 1985$)	(1985$/kWh) *
Level 8	98	61	37	0.16
Level 8/12	166	210	(44)	(0.12)
Level 12/AC	111	189	(78)	(0.35)

* Per unit values, in 1985$/kWh, represent the present value of savings over the lifetime of the appliances (12 years).

Since the rate impact costs are always benefits, the impact of the policies on ratepayers is positive. In absolute terms, the Level 8/12 policy has the highest value, because it saves the most energy. On a per unit basis, however, the policy targeting peak electrical demands, Level 12/AC, has the highest value, because it saves relatively more capacity.

From a societal perspective, only the Level 8 standard yields positive benefits. The Level 8/12 policy has slightly negative impacts and the Level 12/AC has very negative impacts. It is instructive to note the symmetry in the results for the Level 8 and Level 12/AC policy cases. Both policies save similar amounts of energy. The cost premium for the Level 12/AC policy, however, is more than three times that of the Level 8 policy. In other words, the cost premium does not save more energy; it saves capacity. These capacity savings, moreover, only increase the avoided production cost benefits by about twenty percent. They are easily outweighed by the size of the cost premium.

Our assumptions regarding both the choice of social discount rate and the cost of efficient appliances are uncertain. The effect of a lower social discount rate will raise the value of avoided production costs. If we assume linearity in the results on Tables V and VI, a lower social discount rate of, say, 9% will make the Level 8/12 standard cost-effective to society. Nevertheless, only an extremely low social discount rate would make the Level 12/AC standard cost-effective. Similarly, recent cost estimates collected by the California Energy Commission for efficient central air conditioners suggest that our costs may be overestimated by 20-50% [3]. Correcting only a small overestimate makes the Level 8/12 standard beneficial to society. Again, however, substantially revised cost estimates would be required to make the Level 12/AC standard cost-effective to society.

CONCLUSION

This paper has described an integrated analysis method to evaluate the load shape and economic consequences of a DSP for residential appliances. The method employs a "bottom-up" approach that includes end-use forecasts of annual energy use for all fuels and of hourly loads for electricity. The forecasts are based on an engineering/economic model that uses energy prices, and demographic data. The financial analyses rely on avoided production costs calculated with iterative simulations of the utility using a production-cost model. The simulations document the long-run value of supply-side modifications in response to the DSPs. These benefits are compared to costs for both the utility and society. The utility's costs are the under-recovered fixed costs resulting from "lost" electricity sales. Society's costs are the incremental labor and capital costs of the demand-side activity. Our method is particularly well-suited to analyses of energy conserving demand-side technologies, but is not presently capable of modeling other important DSPs such as time-of-use pricing and direct load-control technologies for load management.

The analysis method was demonstrated by a case study of three sets of residential appliance efficiency standards in the Nevada Power Company service territory. The standards were imposed as minimum efficiency requirements for new equipment, starting in 1987. The first standard, Level 8, consisted of moderate minimum efficiencies for all appliances. The second standard, Level 8/12, modified Level 8 by specifying, in addition, very high minimum efficiencies for central air conditioners and heat pumps (namely, SEER=12). The third standard, Level 12/AC, consisted of minimum efficiencies for only space-cooling appliances.

Our major finding was that the load impacts of the standards warranted changes in the timing of future resource additions. We also found that, while each standard increased residential class load factors, the utility and society prefer different standards. From the utility perspective, all standards were cost-effective. The greatest benefit results from the standards that result in the highest class load factors, which we labelled Level 8/12 and Level 12/AC. The Level 8/12 standard produced the largest savings since it saved the most energy, but the Level 12/AC standard had higher per unit values. Conversely, the only standard that is cost-effective from society's perspective is the Level 8 standard, which produced the smallest increase in class load factor. These last results depend strongly on the choice of social discount rate and the cost of efficient appliances. If a lower disount rate is used or uncertainty in the equipment costs is reduced, both perspectives may benefit from the standards analyzed.

ACKNOWLEDGEMENT

The work described in this paper was funded by the Assistant Secretary for Conservation and Renewable Energy, Office of Building and Community Systems, Building Systems Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. We also acknowledge the cooperation of the Nevada Power Company in developing our case study.

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